State of Utah

Department of Environmental Quality

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DIVISION OF AIR QUALITY
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DAQE-AN0327009-04

February 27, 2004

George W. Cross, President
Intermountain Power Service Corporation
850 W Brush Wellman Road
Delta, Utah 84624

Dear Mr. Cross:

Re: Approval Order: CO PSD Major Modification of Approval Order DAQE-049-02, to Add OFA on IPP Units1 and 2, Millard County – CDS A, ATT, Title V, Title IV, NSPS
Project Code: N0327-009

The attached document is the Approval Order (AO) for the above-referenced project.

Future correspondence on this Approval Order should include the engineer's name as well as the DAQE number as shown on the upper right-hand corner of this letter. Please direct any technical questions you may have on this project to Ms. Milka M. Radulovic. She may be reached at (801) 536-4232.

Sincerely,

/S/ 2/26/04

Richard W. Sprott, Executive Secretary
Utah Air Quality Board

RWS:MR:re

cc: Central Utah Public Health Department
Mike Owens, EPA Region VIII

STATE OF UTAH

Department of Environmental Quality

Division of Air Quality

APPROVAL ORDER: CO PSD MAJOR MODIFICATION OF DAQE-049-02, TO ADD OFA ON IPP UNIT 1 AND 2

Prepared By: Milka M. Radulovic, Engineer
(801) 536-4232
Email: Milkar@utah.gov

APPROVAL ORDER NUMBER

DAQE-AN0327009-04

Date: February 27, 2004

Intermountain Power Service Corporation
Source Contact
Rand Crafts
(435) 864-6494

Richard W. Sprott
Executive Secretary
Utah Air Quality Board

Abstract

Intermountain Power Service Corporation (IPSC) operates the Intermountain Generating Station (IGS) coal fired steam-electric plant, consisting of two 950 MW units approved in the DAQE-049-02), located near Delta in Millard County. IPSC is requesting a modification to their current approval order (AO) DAQE-049-02 to install overfire air to control combustion and NO_x in order to accommodate the restriction on NO_x emissions imposed by the Acid Rain Program regulations. In addition, IPSC is proposing:

- ***Replacement-in-kind for the Boilers 1 & 2 low-NO_x burners***
- ***To replace power supplies and motor drives to induced fans***
- ***To clarify and specify where surface-heating area was actually to be added in the Boilers 1 & 2***
- ***Convert minor indoor fugitive emissions to point source emissions***
- ***To upgrade plant Distributed Control System***
- ***Minor changes in the descriptions for clearness***

Projected emission changes from this project are from zero to a potential 7,900 ton decrease from the current NO_x PTE with concurrent increase of CO from zero to a potential 9,700 tons. Other pollutants emission rates, stack mass flow, stack temperatures, air contaminant types, and concentrations of air contaminants will remain the same. This project represents a major modification under the Prevention of Significant Deterioration (PSD) program since the proposed physical change can result in the significant emission increase for CO.

Air quality impact analysis of the CO maximum emission increases was performed and it showed that one (1) and eight (8) hours impacts were well below significant impact levels. Furthermore, potential reduction in the target emissions of NO_x is expected to improve visibility and expand available NO_x increments.

Millard County is an attainment area of the National Ambient Air Quality Standards (NAAQS) for all pollutants. New Source Performance Standards (NSPS), Subpart Da and Subpart Y apply to this source at this time. National Emission Standard for Hazardous Air Pollutants (NESHAP) do not apply to this source. However, it is expected in near future NESHAP for new and existing coal and oil-fired electrical utility steam generating units. The proposed NESHAP would implement section 112(d) of the Clean Air Act by requiring certain coal- and oil-fired electric utility steam generating units to meet HAP emissions standards reflecting the application of the maximum achievable control technology (MACT). Boilers 1 & 2 are also Group 1, Phase II units under the Acid Rain Program. IPSC is a PSD major source of NO_x, SO_2, CO, and PM_{10}. Title V of the 1990 Clean Air Act applies to this source. The Title V permit must be modified prior to operation of this modification.

The project has been evaluated and found to be consistent with the requirements of the Utah Administrative Code Rule 307 (UAC R307). A public comment period was held in accordance with UAC R307-401-4 and comments were received. The comments were evaluated and no comment was found to be adverse to the proposed AO. This air quality Approval Order (AO) authorizes the project with the following conditions, and failure to comply with any of the conditions may constitute a violation of this order.

General Conditions:

1. This Approval Order (AO) applies to the following company:

   Intermountain Power Service Corporation
   850 West Brush Wellman Road
   Delta, Utah 84624
   Phone Number: (435) 864-4414
   Fax Number: (435) 864-6670

   The equipment listed below in this AO shall be operated at the following location:

   PLANT LOCATION:

   850 West Brush Wellman Road, Delta, Millard County, Utah

   Universal Transverse Mercator (UTM) Coordinate System: datum NAD27
   4,374.4 kilometers Northing, 364.2 kilometers Easting, Zone 12

2. All definitions, terms, abbreviations, and references used in this AO conform to those used in the Utah Administrative Code (UAC) Rule 307 (R307) and Title 40 of the Code of Federal Regulations (40 CFR). Unless noted otherwise, references cited in these AO conditions refer to those rules.

3. The limits set forth in this AO shall not be exceeded without prior approval in accordance with R307-401.

4. Modifications to the equipment or processes approved by this AO that could affect the emissions covered by this AO must be reviewed and approved in accordance with R307-401-1.

5. All records referenced in this AO or in applicable NSPS and/or NESHAP and/or MACT standards, which are required to be kept by the owner/operator, shall be made available to the Executive Secretary or Executive Secretary's representative upon request, and the records shall include the five-year period prior to the date of the request. Records shall be kept for the following minimum periods:

   A. Emission inventories Five years from the due date of each emission statement or until the next inventory is due, whichever is longer.

   B. All other records Five years

6. Intermountain Power Service Corporation (IPSC) shall install overfire air system on Boiler #1 and Boiler #2, perform replacement in kind of the Boiler #1 and Boiler #2 Low-NO_x burners (where needed) and shall conduct its operations of the Intermountain Generating Station (IGS) coal fired electric steam plant in accordance with the terms and conditions of this AO, which was written pursuant to IPSC's Notice of Intent submitted to the Division of Air Quality (DAQ) on March 24, 2003 and additional information submitted to the DAQ September 23, 2002, November 14, 2002, January 23, 2003, September 25, 2003, November 3, 2003, November 10, 2003, November 19, 2003, February 20, 2004 and February 26, 2004.

7. This AO shall replace the AOs (DAQE-049-02 and DAQE-AN0327012A-03) dated January 11, 2002 and May 27, 2003.

8. The approved installations shall consist of the following equipment or equivalent*:

A. Unit #1 Coal Fired Boiler (Subject to NSPS, Subpart Da) equipped with Low NO_x burners with maximum heat input of 248 MMBtu/hr per each burner.
Rating - 9,225 x 10^6 Btu/hr (MMBtu/hr)
B. Unit #2 Coal Fired Boiler (Subject to NSPS, Subpart Da) equipped with Low NO_x burners with maximum heat input of 248 MMBtu/hr per each burner
Rating - 9,225 MMBtu/hr
C. Coal railcar unloading dust collector 1A
D. Coal railcar unloading dust collector 1B
E. Coal railcar unloading dust collector 1C
F. Coal railcar unloading dust collector 1D
G. Coal truck unloading dust collector 2
H. Coal reserve reclaim dust collector 3
I. Coal transfer building #1 dust collector 4
J. Coal transfer building #2 dust collector 5
K. Coal transfer building #4 dust collector 6
L. Coal crusher building dust collector 11
M. U1 Generation building coal dust collector 13A
N. U1 Generation building coal dust collector 13B
O. U2 Generation building coal dust collector 14A
P. U2 Generation building coal dust collector 14B
Q. Coal pile-active and reserve
R. Coal Stackout
S. Fuel oil tank 1A
Capacity - 675,000 gallons
T. Fuel oil tank 1B
Capacity - 675,000 gallons
U. Limestone unloading dust collector 1A
V. Limestone unloading dust collector 1B
W. Limestone transfer dust collector 1
X. Limestone reclaim dust collector 2
Y. Limestone silo bin vent filter
Z. Limestone crusher dust collector 3
AA. Limestone preparation dust collector 4
BB. Limestone storage pile
CC. Lime silo dust collector 1
DD. Lime hopper dust collector 2
EE. Soda ash silo dust collector 3
FF. Soda ash hopper dust collector 4
GG. Fly ash silo bin vent filter 1A
HH. Fly ash silo bin vent filter 1B
II. Combustion byproducts stackout & stockpile
JJ. Combustion byproducts landfill
KK. Unit 1 cooling tower 1A
LL. Unit 1 cooling tower 1B
MM. Unit 2 cooling tower 1A
NN. Unit 2 cooling tower 1B

OO. Coal sample preparation building dust collector
PP. Sandblast facility dust collector
QQ. U1 Generation building vacuum cleaning dust collector
RR. U2 Generation building vacuum cleaning dust collector
SS. U1 Fabric filter vacuum cleaning dust collector
TT. U2 Fabric filter vacuum cleaning dust collector
UU. GSB vacuum cleaning dust collector
VV. Guzzler truck dust collector
WW. Emergency diesel generators
1A, rated at - 4,000 Hp
1B, rated at - 4,000 Hp
1C, rated at - 4,000 Hp
XX. Solvent washers
YY. Diesel driven fire pump rated at 290 Hp 1B
ZZ. Diesel driven fire pump rated at 290 Hp 1C
AAA. Auxiliary boiler 1A (not subject to NSPS)
Rating - 166 MMBtu/hr
BBB. Auxiliary boiler 1B (not subject to NSPS)
Rating - 166 MMBtu/hr
CCC. Coal Conveyors
DDD. Paint booth/shops
EEE. Engine driven equipment including compressors, generators, hydraulic pumps and diesel fire pumps
FFF. Bulb recycling crusher
GGG. Laboratory fume hoods
HHH. Gasoline tank
Capacity - 500 gallons
III. Diesel tank
Capacity - 10,000 gallons
JJJ. Diesel day tanks
Capacity - not exceeding 560 gallons per tank
KKK. Mobile oil storage tanks
Capacity - not exceeding 12,000 gallons per tank
LLL. Turbine lube oil units
Capacity - not exceeding 40,000 gallons per unit
MMM. Underground storage diesel tank
Capacity - 20,000 gallons
NNN. Underground storage gasoline tank
Capacity - 6,000 gallons

OOO. Used oil tank
Capacity - 10,000 gallons
PPP. Class III Industrial Waste Landfill
QQQ. Paved haul roads
RRR. Unpaved Haul roads
SSS. Coal truck unloading grating
TTT. Two Helper cooling towers
UUU. Boiler #1 and Boiler #2 over-fire air-ports system, 16 per each boiler

* Equivalency shall be determined by the Executive Secretary.

9. Intermountain Power Service Corporation shall notify the Executive Secretary in writing when the installation of the equipment listed in Condition #8.A., B. and UUU has been completed and is operational, as an initial compliance inspection is required. To insure proper credit when notifying the Executive Secretary, send your correspondence to the Executive Secretary, attn: Compliance Section.

If construction and/or installation has not been completed within eighteen months from the date of this AO, the Executive Secretary shall be notified in writing on the status of the construction and/or installation. At that time, the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation. If continuous construction and/or installation cannot be demonstrated, the Executive Secretary may revoke the AO in accordance with R307-401-11.

Limitations and Tests Procedures

10. Except for start-up, shut-down, planned/maintenance outage, or malfunction, emissions to the atmosphere at all times from the indicated emission points shall not exceed the following rates and concentrations:

A. Each Main Boiler Stack

Pollutant	lb/ 10^6 Btu heat input	
PM_{10}	0.0184 *	lb/ 10^6 Btu heat input
SO_2	0.138 **	lb/ 10^6 Btu heat input based on 30-day rolling-average 10.0 % of the potential combustion concentration
NO_x	0.461**	lb/ 10^6 Btu heat input based on 30-day rolling-average

Testing Status (To be applied above)

* Test once a year. The Executive Secretary may require testing at any time.
**Compliance for NO_x and SO_2 emissions shall be demonstrated through use of a continuous emissions monitoring system as outlined in Condition 24.

B. Dust Collectors

Pollutant/Source PM_{10}	Differential pressure range across the dust collector (Inches of water gage)
Rail car unloading (4 units)	0.5 to 12*
Transfer building one	0.5 to 12*
Unit one 13A	0.5 to 12*
Transfer building two	0.5 to 12*
Transfer building four	0.5 to 12*
Crusher building one	0.5 to 12*
Unit one 13B	0.5 to 12*
Unit two 14A	0.5 to 12*

Unit two 14B.. 0.5 to 12*
Limestone preparation building.............. 0.5 to 1 2*

*If differential pressure is less than 2 inches or greater than 10 inches, work orders will be written to investigate. Dust collector may run in the 0.5 to 2 or 10 to 12 range if reason is known. Intermittent recording of the reading is required on a monthly basis. The instrument shall be calibrated against a primary standard annually. Preventive maintenance shall be done quarterly on each baghouse.

C. Each Auxiliary Boiler (Rated at 166 x 10^6 Btu/hr)

Pollutant	lb/ 10^6 Btu heat input	lbs/hr*
PM_{10}	0.10	20
SO_2	0.69	100
NO_x	0.35	58

*Testing shall be done in accordance with the requirements from the most current Title V permit.

L. Existing Source Operation

For an existing source/emission point, the production rate during all compliance testing shall be no less than 90% of the maximum production achieved in the previous three (3) years.

E. Notification

The Executive Secretary shall be notified at least 30 days prior to conducting any required emission testing. A source test protocol shall be submitted to DAQ when the testing notification is submitted to the Executive Secretary.

The source test protocol shall be approved by the Executive Secretary prior to performing the test(s). The source test protocol shall outline the proposed test methodologies, and stack to be tested. A pretest conference shall be held, if directed by the Executive Secretary.

F. Sample Location

The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other methods as approved by the Executive Secretary. Access that meets the standards of the Occupational Safety and Health Administration (OSHA) or the Mine Safety and Health Administration (MSHA) shall be provided.

G. Volumetric Flow Rate

40 CFR 60, Appendix A, Method 2
H. PM_{10}

Compliance determination procedures and stack testing shall be performed according to 40 CFR 60, Appendix A, Method 5B.

I. Carbon Monoxide (CO)

40 CFR 60, Appendix A, Method 10, or other testing methods approved by the Executive Secretary.

J.Nitrogen Oxides (NO_x)

40 CFR 60, Appendix A, Method 7, 7A, 7B, 7C, 7D, 7E, or other testing methods approved by the Executive Secretary.

K. Calculations for Test Results

To determine mass emission rates (lb/hr, etc.) the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors determined by the Executive Secretary, to give the results in the specified units of the emission limitation.

D **Each Main Boiler Stack**

Pollutant	lbs/hr*
CO...	1320 lb/hr rate (monthly block average)

*Compliance demonstration:

(1) Combustion flue gas percent O_2 shall be monitored and recorded at least once per 15 minutes at the exit path of each boiler. Measurements are weighted average results collected from several sensors located in each boiler exit flue path. Calibrations shall be maintained within manufacturers recommendations.

(2) OFA operating condition shall be monitored and recorded at least once per 15 minutes. Monitoring shall include OFA position and status: i.e., No OFA, 1/3 OFA, 2/3 OFA, throttled or open. Operational status is measured by OFA system damper position.

(3) Using the data above and this formula, CO concentration (ppmdv) shall be calculated and averaged hourly, except for periods of calibration, maintenance, or malfunction of the instrumentation or data system. For periods of calibration, maintenance, or malfunction of instrumentation or data collection system, missing data shall be back filled following procedures similar to 40 CFR Part 75 Subpart D, and used for compliance determinations.

$$[Cppmvd] = n * (O_2\%)^a$$

Where:
[Cppmvd] = concentration of CO in parts per million volume dry
n = curve specific factor obtained from the table below
$O_2\%$ = percent O_2 measured at the boiler stack exit
a = curve specific exponent obtained from the table below

Values for **n** and **a** factors

Pozition	**n**	**a**
No OFA	47259	-7.6817
1/3 OFA	66265	-7.9824
2/3 OFA - throttled	4029.2	-4.0112
2/3 OFA - full open	1372.4	-3.0919

(4) The hourly mass emission rates in lb per hour shall be calculated using the following formula or any necessary conversion factors determined by the Executive Secretary, to give the results in the specified units of the emission limitation.

$[C_{lb/hr}] = [C_{ppmvd}] * 2.59 * 10^{-9} * MW * Fd * 20.9/(20.9-O_2\%) * H_l$

where:

$[C_{lb/hr}]$ = pound per hour emission rate
$[C_{ppmvd}]$ = hourly average of CO emissions in parts per million
$2.59*10^{-9}$ = conversion factor for pound per standard cubic feet
MW = molecular weight of CO
F_d= F factor to convert standard cubic feet per million Btu heat input.
$O_2\%$ = hourly average of excess combustion oxygen, in percent
H_l = heat input, in million Btu per hour

(5) By the 15th day of each month, the monthly average of CO emissions in lb/hr shall be calculated by using the hourly average CO emission values in lb/hr.

(6) Initial stack testing shall be performed on Unit#2 Boiler. The stack test results shall be used to verify the overfire air system CO and O_2 dependency relationship developed for the Unit#1 Boiler and shall not be used for compliance determination.

(a) Frequency. Initial test shall be performed as soon as possible and in no case later than 180 days after the start up of OFA system installation on Unit#2 Boiler. The source may also be tested at any time if directed by the Executive Secretary.

(b) Notification. The Executive Secretary shall be notified at least 30 days prior to conducting any required emission testing. A source test protocol shall be submitted to DAQ when the testing notification is submitted to the Executive Secretary.

The source test protocol shall be approved by the Executive Secretary prior to performing the test(s). The source test protocol shall outline the proposed test methodologies, and stack to be tested. A pretest conference shall be held, if directed by the Executive Secretary.

(c) Methods.

Sample Location - The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other methods as approved by the Executive Secretary. Access that meets the standards of the Occupational Safety and Health Administration (OSHA) or the Mine Safety and Health Administration (MSHA) shall be provided.

Volumetric Flow Rate - 40 CFR 60, Appendix A, Method 2

Carbon Monoxide (CO) - CO shall be determined according to 40 CFR 60, Appendix A, Method 10, or other testing methods approved by the Executive Secretary.

(d) Production Rate During Testing. The production rate during all compliance testing shall be no less than 90% of the maximum production achieved in the previous three (3) years.

7. Results of all the monitoring shall be kept for all period.

11. Visible emissions from the following emission point sources shall not exceed the following values:

A. All abrasive blasting - 40% opacity
B. All other points - 20% opacity

Opacity observations of emissions from stationary sources shall be conducted according to 40 CFR 60, Appendix A, Method 9.

For sources that are subject to NSPS, except for the units equipped with continuous opacity monitoring system, opacity shall be determined by conducting observations in accordance with 40 CFR 60.11(b) and 40 CFR 60, Appendix A, Method 9.

12. The following consumption limit shall not be exceeded:
50,000 barrels of fuel oil consumed per calendar year in the auxiliary boilers.

To determine compliance with this annual limit, the owner/operator shall calculate a total by the January 20th of each year using data from the previous 12 months (ending with December 31). Records of consumption shall be kept for all periods when the auxiliary boilers are in operation. Consumption shall be determined by fuel oil totalizer records. The records of consumption shall be kept on a monthly basis.

13. Emergency generators shall be used for routine maintenance and electricity producing operation only during the periods when regular electric power supply is interrupted, except for routine engine maintenance and testing. Records documenting generator usage shall be kept in a log and shall show the date the generator was used, the duration in hours of generator usage, and the reason for each usage.

14. The diesel driven fire pumps shall be operated on an emergency basis only, except for routine engine and fire system maintenance and testing. Records documenting diesel driven fire pump usage shall be kept in a log and shall show the date the diesel driven fire pump was used, the duration in hours of use, and the reason for each usage.

Roads and Fugitive Dust

15. IPSC shall abide by the latest fugitive dust control plan submitted to the Executive Secretary for control of all dust sources associated with the Intermountain Power Generation site.

    Any haul road speeds established in the plan shall be posted.

16. The facility shall abide by all applicable requirements of R307-205 for Fugitive Emission and Fugitive Dust sources.

Fuels

17. The owner/operator shall combust only bituminous and subbituminous coals as primary fuels and shall only use diesel oil or natural gas during the startups, shutdowns, maintenance, performance tests, upsets and for flame stabilization in the 9,225 x 10^6 Btu/hr boilers. Only No. 2 oil shall be used in 166 x 10^6 Btu/hr boilers. The owner/operator may fuel-blend self-generated used oil with coal at the active coal pile reclaim structure providing that self-generated used oil has not been mixed with hazardous waste.

18. The sulfur content of any fuel oil combusted shall not exceed:

    A. 0.85 lb per x 10^6 Btu heat input for fuel oil used in the main boilers.
    B. 0.58 percent by weight for fuel oil combusted in the auxiliary boilers.

    The sulfur content shall be determined by ASTM Method D-4294-89 or approved equivalent. Certification of fuel oil shall either be by IPSCs own testing or test reports from the fuel oil marketer.

Federal Limitations and Requirements

19. In addition to the requirements of this AO, all applicable provisions of 40 CFR 60, New Source Performance Standards (NSPS) Subpart A, 40 CFR 60.1 to 60.18 and Subpart Da, 40 CFR 60.40a to 60.49a (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978) and Subpart Y, 40 CFR 60.250 to 60.254 (Standards of Performance for Coal Preparation Plants) apply to this installation.

20. In addition to the requirements of this AO, all applicable provisions of 40 CFR Part 72, 73, 75, 76, 77, and 78 - Federal regulations for the Acid Rain Program under Clean Air Act Title IV apply to this installation.

Records & Miscellaneous

21. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any equipment approved under this AO including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Executive Secretary which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. All maintenance performed on equipment authorized by this AO shall be recorded, and the records shall be maintained for a period of two years.

22. The owner/operator shall comply with R307-150 Series. Inventories, Testing and Monitoring.

23. The owner/operator shall comply with R307-107. General Requirements: Unavoidable Breakdowns.

Monitoring - Continuous Emissions Monitoring

24. The owner/operator shall install, calibrate, maintain, and continuously operate a continuous emissions monitoring system (CEMs) on the main boilers stacks and SO_2 removal scrubbers inlets. The owner/operator shall record the output of the system, for measuring the opacity, SO_2, NO_x, CO_2 emissions. The monitoring system shall comply with all applicable sections of R307-170, UAC; and 40 CFR 60, Appendix B.

    All continuous emissions monitoring devices as required in federal regulations and state rules shall be installed and operational prior to placing the affected source in operation.

    Except for system breakdown, repairs, calibration checks, and zero and span adjustments required under paragraph (d) 40 CFR 60.13, the owner/operator of an affected source shall continuously operate all required continuous monitoring devices and shall meet minimum frequency of operation requirements as outlined in 40 CFR 60.13 and Section UAC R307-170.

25. In order to demonstrate that the modifications approved in AO number DAQE-049-02 did not result in significant emission increases (as defined in R307-101-2), the rolling 12-month period (that is compiled quarterly) main boilers 1&2 fuel consumption data (MMBtu/hr) and emissions from their stack flues, except CO shall be monitored for at least 5 years from the date the units begin fully using the modifications described therein as regular operation.

    IPSC shall be required to obtain a PSD permit if:

    a. IPSC fails to comply with the record keeping and reporting requirements of the WEPCO rule, or
    b. The submitted information indicates that emissions, except CO, without credits from the OFA system operation, have increased above the significant emission increases as a consequence of the changes.

Records of NO_x and SO_2 shall be obtained through the use of each unit CEM.system. Records of PM_{10} shall be based on annual stack tests outlined in the Condition 9. Records for the rest of pollutants, except CO, shall be based on the EPA's Compilation of Air Pollutant Emission Factors (AP-42) or industry specific published emission factors (such as Electric Power Research Institute, Edison Electric Institute or IPSC own testing).

26. In order to demonstrate that the modifications approved in AO number DAQE-049-02 and for the OFA system addition for the boilers 1&2 did not result in significant emission increases (as defined in R307-101-2), the rolling 12-month period (that is compiled quarterly) main boilers 1&2 fuel consumption data (MMBtu/hr) and emissions from their stack flues, except CO, shall be monitored for at least 5 years from the date the units begin fully using the modifications described therein as regular operation.

IPSC shall be required to obtain a PSD permit if:

a. If IPSC fails to comply with the record keeping and reporting requirements of the WEPCO rule, or
b. The submitted information indicates that changes made in the AO number DAQE-049-02 and OFA system additions combined emissions, except CO, have increased above the significant emission increases as a consequence of the changes.

Records of NO_x and SO_2 shall be obtained through the use of each unit CEM system. Records of PM_{10} shall be based on annual stack tests outlined in the Condition 9. Records for the rest of pollutants, except CO, shall be based on the EPA's Compilation of Air Pollutant Emission Factors (AP-42) or industry specific published emission factors (such as Electric Power Research Institute, Edison Electric Institute or IPSC own testing).

The Executive Secretary shall be notified in writing if the company is sold or changes its name.

This AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including R307.

A copy of the rules, regulations and/or attachments addressed in this AO may be obtained by contacting the Division of Air Quality. The Utah Administrative Code R307 rules used by DAQ, the Notice of Intent (NOI) guide, and other air quality documents and forms may also be obtained on the Internet at the following web site: http://www.eq.state.ut.us/eqair/aq_home.htm

The annual emission estimations below include point source, fugitive emissions, fugitive dust and do not include road dust, tail pipe emissions, grandfathered emissions etc. These emissions are for the purpose of determining the applicability of Prevention of Significant Deterioration, nonattainment area, maintenance area, and Title V source requirements of the R307. <u>They are not to be used for determining compliance</u>.

The Potential To Emit (PTE) emissions for the IPSC power generation plant are currently calculated at the following values:

	Pollutant	Tons/yr
A.	PM_{10}	3,286.7
B.	SO_2	11,332.3
C.	NO_x	37,868.2

D. CO 11,692.3
E. VOC 63.91
F. HAPs 82.67
   Lead 0.39168
   Beryllium 0.00892
   Mercury 0.3135
   Fluorides (HF) 16.8
   Sulfuric Acid 8.8
   Other non-VOC HAPs 93.2

Approved By:

Richard W. Sprott, Executive Secretary
Utah Air Quality Board